Alberta

PETROLEUM MARKETING COMMISSION

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October 30, 1981.

INFORMATION BULLETIN RE ALBERTA COST OF SERVICE

The Alberta Cost of Service Information Bulletin for the month of September, 1981 is attached:

The Information Bulletin consists of:

1. Copies of any special Orders or Determinations issued by the Commission during the month with respect to Alberta Cost of Service, and notice of any Statements of Objection which have been received during the month; and

2. Alberta Cost of Service Determinations for the month.

In the case of gas intended to be removed from Alberta, the cost of service determined under Sections 9 and 15(3)(a) of The Natural Gas Price Administration Act for each month is based on estimated figures for that month, adjusted to allow for differences between the estimated and actual figures for the previous month.

In the case of gas intended for consumption within Alberta, the amount estimated as cost of service under Sections 9 and 15(3)(b) of the Act were made under the Commission's general directive for the Alberta cost of service.

All determinations are on gross or higher heating value on a dry basis at 15°C and an absolute pressure of 101.325 kPa (kilopascal).

Yours very truly,

ALBERTA PETROLEUM MARKETING COMMISSION

R. H. Purdy

R. H. PURDY
Vice-Chairman

Attachment

INFORMATION BULLETIN
ALBERTA COST OF SERVICE DETERMINATION
PURSUANT TO THE NATURAL GAS PRICE ADMINISTRATION ACT
MONTH OF SEPTEMBER, 1981

Section 15(3)(a)	Average Rate Per Gigajoule (GJ) * Cents
Alberta and Southern Gas Co. Ltd.	
- signatory	37.391
- non-signatory	47.974
Canadian Montana Gas Company Limited	
- Produced Gas	170.162
- Purchased Gas	170.140
Consolidated Natural Gas Limited	28.258
Many Islands Pipe Line (Canada) Limited	
- Purchased Gas	25.792
- North Sibbald (Agent)	5.713
- Saddle Lake	16.950
- Esther	11.478
Pan-Alberta Gas Ltd.	48.686
Progas Limited	27.301
Sulpetro Limited	26.280
TransCanada PipeLines Limited	38.100
Westcoast Transmission Company	
- Husky Oil Ltd.	116.432
- Petrogas Processing Ltd. et al	20.532
Westcoast Transmission Company (Alberta) Limited	
- North	37.378
- Triassic E	.474

Section 15(3)(b)

Albersun Pipelines Ltd.	21.500
Beaver River Utilities	21.500
Canadian Industries Ltd.	21.500
Canadian Western Natural Gas Co. Ltd.	21.500
Chevron Standard Ltd.	21.500
Coronation, Town of	21.500
County of Paint Earth	21.500
Cretaceous Pipelines Ltd.	21.500
Dalum Gas Co-op	21.500
Devon, Town of	21.500
Dresser Industries, Inc.	21.500
Dunmore Natural Gas Systems	21.500

Durr, M	21.500
Ehrut, Mrs.	21.500
Gas Alberta	21.500
Grande Prairie Transmission Co. Ltd.	21.500
High Prairie, Town of	21.500
Houg Cement Limited	21.500
Husky Oil Operations	21.500
Imperial Oil Limited	21.500
Inland Oil & Gas Ltd.	21.500
Interprovincial Gas Co. (1964) Ltd.	21.500
LK Ranches	21.500
Norcen Energy Resources Ltd.	21.500
Northwestern Utilities Ltd.	21.500
PanCanadian Petroleum Limited	21.500
ICG Utilities (Plains Western) Ltd.	21.500
Redwater, Town of	21.500
Rosemary Gas Co-op	21.500
Steinback Ranching	21.500
Suncor Inc.	21.500
Superior Natural Gas Services Ltd.	21.500
Syncrude Canada Ltd.	21.500
Tirol Dehydration Ltd.	21.500
Tirol Gas Co-op	21.500
Valley Gas Company Limited	21.500
Village of Thorhild	21.500
Westburne Petroleum & Minerals Ltd.	21.500
Wintering Hills	21.500

NOTES

* Calculated on a gross and dry heating value basis at 101.325 kPa (kilopascal) and 15°C.

NOTICE

For the month of September, 1981
The price adjustment for gas is $0.87 00/GJ
The Alberta Reference Price is 1.70 162/GJ

DETERMINATION 81-06 (PRO)
ALBERTA COST OF SERVICE
THE NATURAL GAS PRICE ADMINISTRATION ACT

APPLICATION

By application dated March 23, 1981 and additional information filed on May 22, May 26, June 1, and June 26, 1981 ProGas Limited (ProGas) requests approval for the structure of an Alberta cost of service as follows:

A deferral of current operating costs and return:
- the amortization of initial development costs, the monthly operating costs and the return for the first five months will be deferred with the amount so deferred each month based on the ratio of volume of gas purchased from TCPL to the total volume of gas purchased during the month.

A rate base comprised of:
- initial development costs incurred during the period July 15, 1978 to the date of commencement of initial deliveries of natural gas;
- interest on initial development costs capitalized over the above period;
- the net unamortized balance of furniture and leasehold improvements;
- an allowance for working capital consisting of 1/8 of the projected annual cash operating expenses excluding the cost of gas; and
- the net unamortized balance of deferred operating costs and return.

Amortization rates based on:
- a five year straight line amortization of furniture and leasehold improvements;
- a straight line amortization of initial development costs over the 15 year life of the provincial removal permit excepting the deferral of a portion of the amount to be amortized as described above;
- a straight line amortization of deferred operating costs and return over a five year period.

A rate of return on rate base of 14.35% derived as follows:

Capital Structure	Ratio	Cost Rate	Cost Component
Bank loan	12.106%	18.50%	2.24%
Debt	37.886%	15.00%	5.68%
Subtotal	49.992%		7.92%
Equity			
Preferred	26.368%	8.25%	2.175%
Common	23.640%	18.00%	4.255%
Total	100.000%		14.350%

In support of the cost components ProGas indicates that:

-interest on the bank loan is at bank prime, assumed to be 17.5%, plus 1%;

-debt cost of 15% is based on the cost estimated by an investment firm of five year money that would be obtained by private placement to a company such as ProGas (BBB rating);

-the preferred share dividend rate of 8.25% approximates, on an after tax basis, the 15% per annum interest rate on debt assuming an income tax rate of 47%;

- a differential of 3% is applied to the cost of unfunded debt to arrive at a return on common equity of 18% and a review of the return on common equity received by other shippers in Alberta indicates a differential between rate of return on common equity and debt in the range of 3% to 6%;

-ProGas further states in support of the return on common equity:

"We also believe the business and financial risks for ProGas are somewhat greater than that of other companies operating under a cost of service arrangement. These risks are as follows:

1) Our total asset and equity base is extremely small in comparison with dollar magnitude of our contractural arrangements. We will be responsible for the sale of some $2.7 billion (Canadian) of natural gas to the U.S. based on present prices. As U.S. exports decline and terminate, we continue to sell the volumes until the year 2005 to Canadian markets, again involving in excess of $3 billion worth of sales based on present prices. It is apparent, therefore, that notwithstanding the soundness of our purchase and

sales contracts, that any unforeseen problems with respect to take or pay, or even the collection of monies on a timely basis, do present substantial risks.

2) ProGas and its producer sponsors have undertaken a back-stopping arrangement with Nova, whereby if the postage stamp cost of service is no longer in effect, we undertake to ensure them of full recovery of their investment (some $70 million). Should this eventuality occcur and our gas purchases decline more rapidly than anticipated, then equity of ProGas could be wiped out quickly and the sponsor companies of ProGas would be liable for any default of ProGas. In this connection, because of our smaller volumes, and a more restrictive or less diversified supply base, our risks are greater in this regard than those of the major gas purchasers in Alberta."

DECISION

1. Rate base shall consist of an allowance for necessary working capital and the net unamortized balance of:
   a) the costs of office furniture and equipment,
   b) the costs of leasehold improvements, and
   c) initial development costs including deferred operating costs and deferred rate of return.

2. Initial development costs will include project costs incurred during the development period from July 15, 1978 to June 20, 1981, the date of commencement of gas deliveries, and a capitalized interest factor calculated at bank prime plus 1% as in effect during the development period.

3. The allowance for working capital shall consist of 1/8 of the projected annual cash operating expenses excluding the cost of gas.

4. The portion of operating costs and return that may be deferred during the period of load buildup will be based on the ratio of gas purchased from TCPL to the total quantity of gas purchased during the month.

5. Office furniture and equipment and leasehold improvements will be amortized on a straight line basis over a five

year period; development costs including deferred operating costs and deferred return are to be amortized on a straight line basis over the life of the provincial removal permit.

6. The allowed rate of return on rate base shall be 14%.

7. Income taxes calculated on a flow-through basis, taking maximum benefit of deductions for tax purposes, are eligible for recovery in Alberta cost of service.

8. This decision is effective from June 20, 1981.

REASONS FOR DECISION

The capital structure of the company, with the exception of bank debt, is created by a conversion of the ProGas participants' interests in the project to debt, preferred and common shares of ProGas Limited. Interest on development costs is capitalized and allocated among debt, preferred and common equity in the same proportion as are the development costs.

The capital structure used by ProGas to derive the requested rate of return included bank financing of working capital requirements which the Commission has excluded as inappropriate. The estimated amount for interest on initial development expenses was calculated by ProGas using an interest rate of 14.44% which was derived from the pro-forma capital structure at June 1, 1981 excluding capitalized interest. The Commission has reduced this rate from 14.44% to bank prime in effect during the project period of development plus 1% because the 14.44% reflects financing costs at June 1, 1981 which the Commission does not consider representative for the period involved.

The capital structure contains a high proportion of equity capital, in excess of 50%. However the Commission considers this acceptable having regard to the current stage of development of the company.

The Commission accepts the proposed cost rates to be assigned to the bank loan as 18.5%, to debt as 15% and to preferred share dividends as 8.25%.

With respect to the requested return on common equity, the Commission does not accept there is risk involved in the back-stopping arrangement with Nova because Nova cannot upon its own volition change from a postage stamp cost of service.

The rate of return on common equity of 18% requested by ProGas is considered by the Commission to represent a 3% differential, or risk premium, over the yield on low-risk long term government bonds at the end of May, 1981. The risk premium allowed by the Commission is 2% which results in an allowed rate of return on common equity of 17% and a composite rate of return on rate base of 14%.

DATED THIS 9th day of October, 1981 at Calgary, Alberta.

ALBERTA PETROLEUM MARKETING COMMISSION

D. C. Hetland
Secretary